STATEMENT OF BASIS 8-30-2004
Prevention of Significant Deterioration
Proposed Permit No.: PSD-FDL-R50001-04-01

This document serves as the statement of basis, as required by Title 40 Code of Federal Regulations (40 CFR) part 124, for a Prevention of Significant Deterioration (PSD) air pollution construction permit. This document sets forth the legal and factual basis for permit conditions, with references to applicable statutory or regulatory provisions, including provisions under the federal PSD regulations, 40 CFR 52.21. This statement of basis document is for all interested parties of the permit.

1.0 GENERAL INFORMATION

(A). Applicant and Stationary Source Information

Permitting Authority:	United States Environmental Protection Agency Region 5 (AR-18J) 77 West Jackson Boulevard Chicago, Illinois 60604
Owner:	Great Lakes Gas Transmission Limited Partnership
Operator:	Great Lakes Gas Transmission Company 5250 Corporate Drive Troy, Michigan 48908
SIC Code:	4922, Natural Gas Transmission
Facility Location	Cloquet Compressor Station No. 5 3741 Brandon Road Cloquet, Minnesota 55720 Fond du Lac Band of Lake Superior Chippewa Indian Reservation St. Louis County Contact: Dick Goar, Operations Manager - Bemidji Area (218) 879-1581
Responsible Official:	John J. Wallbillich (248) 205-7426
Permit Contact:	Dorothy Fleming Great Lakes Gas Transmission Company Senior Environmental Specialist (248) 205-7454

Tribal Environmental Contact:	Chris Berini, Environmental Director Fond du Lac Reservation 1720 Big Lake Road Cloquet, Minnesota 55720 (218) 878-8006

(B). Background on the Construction, Operation, and Permitting of Cloquet Compressor Station No. 5

Great Lakes Gas Transmission Limited Partnership (Great Lakes) submitted a 40 CFR Part 71 air pollution operating permit application to Region 5 of the United States Environmental Protection Agency (EPA) on November 12, 1999, for its Cloquet Compressor Station No. 5 (CS #5). CS #5 is located on privately-owned fee land within the exterior boundaries of the Fond du Lac Band of Lake Superior Chippewa Indian Reservation in St. Louis County, Minnesota. The compressor station currently consist of three natural gas fired turbines, each powering its own compressor, and one natural gas-fired standby electrical generator.

Minnesota has been delegated authority by EPA to both issue PSD permits in the stead of EPA, and assure that sources meet applicable New Source Performance Standards (NSPS) for all sources within the State’s jurisdiction. Minnesota has an EPA approved New Source Review (NSR) permit program for construction of new sources or modifications to existing sources which emit air pollutants and do not require a PSD permit. The State also has a combined construction permit and operating permit program. This program is federally approved as meeting the operating permit requirements of title 5 of the Clean Air Act (CAA) and allows the State to issue a single permit meeting the federal requirements of both programs. These Minnesota permit programs, however, are not federally approved as applying to sources in Indian Country. Instead EPA is currently responsible for issuing permits there.

In the late 1990's, Region 5 reviewed the status of sources in Indian Country. It determined that, because CS #5 is located in Indian Country, the construction permits for the modifications (and corresponding combined operating permits) were erroneously issued by the Minnesota Pollution Control Agency (MPCA). This federal permitting action is intended to correct this oversight.

CS #5 was originally constructed prior to federal requirements that a source obtain a pre-construction air pollution permit or meet the requirements of EPA's NSPS. Under the assumption that EPA's delegations and approvals applied, Minnesota subsequently took the following actions:

- In 1989, MPCA issued permit No. 365-89-OT-1 allowing the replacement of an existing gas fired compression turbine with the installation of new emission unit 001, and the operation of existing emission unit 002. Based on the capacity and installation date of emission unit (EU) 001, it is subject to NSPS.

- In 1992, MPCA issued a modification to permit No. 365-89-OT-1 (Amendment No. 1) allowing the construction of a new emission unit, EU 003. It was determined that EU 003 was subject to NSPS, and was also required to go through the PSD permitting process (including a Best Available Control Technology (BACT) analysis).

- In 1994, MPCA issued another modification to permit No. 365-89-OT-1 (Amendment No. 2) adopting a custom fuel sampling schedule as allowed under the NSPS and approved by EPA.

- In 1993, Great Lakes installed a natural gas-fired standby generator (EU 004) to replace the original generator installed in 1968. Great Lakes accepted a limit on EU 004 of 4,500 hours of operation per year in order to keep the net emissions increase from this modification below the PSD significant emission threshold.

- In 1998, MPCA issued a combined Part 70 operating permit/NSR facility wide permit (No. 13700066-001). The facility was required to complete computer dispersion modeling to demonstrate compliance with the NO_x increment consumption by applicable emission units since the minor source baseline date in St. Louis County was triggered. The modeling determined that operation of the electrical generator less than 3000 hours per year would prevent an exceedance of the allowable increment. The 3000 hours per year limit for EU 004 was incorporated into the 1998 MPCA permit.

Because Minnesota did not and currently does not have authority to issue permits to sources in Indian Country, Great Lakes' MPCA issued permits are not valid. Thus, CS #5 does not meet the Part 71 permit requirement of being in compliance with all applicable requirements of the Clean Air Act (CAA), i.e., it constructed without federally valid construction permits.

EPA has reviewed the source's original PSD applications to MPCA and data in EPA's BACT clearinghouse,[1] and believes that, had Great Lakes submitted the same permit applications to EPA at the time they were submitted to MPCA, EPA would have issued permits with the same applicable terms and conditions. EPA believes the facility acted in good faith when applying for the permits with the State. All permit applications acknowledged that the facility was in Indian Country. However, in accordance with the Minnesota delegation agreement of 1988, Indian Country is excluded from the State PSD program.[2] At the time of the permit notices, neither EPA nor the Tribe commented on the legal authority of MPCA to issue the permits. Based on these facts, EPA believes it would place an undue burden on the facility to apply for a new federal PSD permit and undergo a current day BACT and air quality analysis as though the facility had never been constructed.

Because BACT is source specific and is normally based on the controls available at the time a source is to be constructed, EPA is proposing through this federal permit action to accept the BACT analysis and ambient air analyses that were performed at the time the State received the applications, issued the permit and amendments, and the emission units were constructed/modified. EPA is proposing to approve the original 1992 BACT analysis for EU 003, to approve the corresponding emission limit and control technology MPCA determined to be BACT at that time, and add a corresponding weight/time BACT emission limit needed to protect the ambient standards and increments. EPA is proposing a 3000 hour per year operating limit in the PSD permit for EU 004 to protect the PSD increment. Any changes in these permit requirements, physical construction or modification at CS #5, or changes in the historical operating parameters at the facility, may trigger the major modification requirements of PSD and result in a requirement for a new PSD permit application, with corresponding current BACT and ambient analysis review. Concurrently, EPA is also proposing for comment a draft Part 71

---

[1] EPA's BACT clearinghouse contains the BACT emission limit, control technology, and operating parameter determinations made primarily by States for PSD permits for various sources over time.

[2] In accordance with the November 3, 1988, memorandum to MPCA from the Region 5 Regional Administrator clarifying EPA's delegation of PSD authority to Minnesota.

permit incorporating these BACT limits and all other applicable federal requirements.

(C). Facility Description

Great Lakes operates nearly 2,000 miles of underground pipeline, which transports natural gas for delivery to customers in the midwestern and northeastern United States and eastern Canada. The pipeline's 14 compressor stations, located approximately 75 miles apart, operate to keep natural gas moving through the system. Great Lakes owns and operates five compressor stations in Minnesota: St. Vincent Compressor Station #1, Thief River Falls Compressor Station #2, Shevlin Compressor Station #3, Deer River Compressor Station #4, and Cloquet Compressor Station #5. Compressors operated at these stations add pressure to natural gas in the pipeline causing it to flow to the next compressor station. The pipeline normally operates continuously, but at varying loads, 24 hours per day and 365 days per year.

CS #5 is located 17 miles west of Cloquet, near the intersection of county roads 847 and 851, and in St. Louis County, Minnesota. The facility property occupies an area of approximately 20 acres and is owned by Great Lakes.

CS #5 consists of three stationary natural gas-fired turbines, which in turn drive three natural gas compressors. Additionally, one natural gas-fired standby electrical generator provides electrical power for critical operations during temporary electrical power outages and during peak loading.

(D). Area Classification

CS #5 is located on privately-owned fee land within the exterior boundaries of the Fond du Lac Band of Lake Superior Chippewa Indian Reservation. The EPA is primarily responsible for issuing and enforcing any air quality permits for the source until such time that the Tribe or State has EPA approval to do so.

St. Louis County, and all Indian Country within, is designated attainment for all criteria pollutants. CS #5 is within 25 miles of the state of Wisconsin. There are no PSD Class I areas within 100 kilometers of CS #5.

(E). Enforcement Issues

The EPA is not aware of any pending enforcement issues at this facility.

(F). Pollution Control Equipment

Emission control for the turbines consists of the standard combustor technology available at the time of construction for the turbines.

(G). Emission Unit Summary from Great Lakes Application to EPA

Emission Unit	**EU 001**	**EU 002**	**EU 003**	**EU 004**
Unit Type	Turbine/ Compressor	Turbine/ Compressor	Turbine/ Compressor	Standby Electrical Generator
Date Installed	3/1/1989 Replaced a unit originally installed in 1971	1/1/1970	1/1/1992	1/1/1993 Replaced a unit originally installed in 1968
Manufacturer/ Model	General Electric LM 2500	Rolls Royce Avon 76 G	General Electric LM 1600	Caterpillar SR-4
Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Input (MMbtu/hr)	251.1	166.4	184.0	4.8
Stack Height (ft)	39.5	31.0	38.8	10.0
Inside Stack Diameter (ft)	7.25	9.18	6.58	0.67
Stack Temperature (^oF)	936	769	934	813
Stack Flow Rate (ACFM)	341,397	199,174	249,809	5,951
Velocity (ft/sec)	137.83	50.15	122.44	281.32

(H). Potential Emissions

The following tables were calculated by EPA after receipt of the Part 71 application submitted in 1999, and after receiving 2000 emission testing data for compliance and emission inventory purposes. All emission factors are from AP-42 tables published in April 2000, except for NO_x, CO, and VOC. Emission Factors for NO_x, CO, and VOC were calculated from performance test performed at the facility in May 2000. The maximum ambient horsepower rating (HP) for each unit was used when calculating Potential to Emit (PTE) for the system.

Potential to Emit Summary								
EU	**Emission Unit Description**	**PM tpy**	**SO_2 tpy**	**NO_x tpy**	**CO tpy**	**VOC tpy**	**Pb tpy**	**Total HAPs tpy**
001	turbine	7.26	67.75	471.8	128.7	3.52	ND	1.13
002	turbine	4.81	44.90	146.5	384.8	37.61	ND	0.75
003	turbine	5.32	49.64	371.5	13.7	0.48	ND	0.83
004	generator	0.21	0.012	85.8	11.7	2.48	ND	2.04
Total Potential Emissions		17.60	162.30	1075.6	538.9	44.09	ND	4.75

Emission Factors (lb/MMbtu)								
EU	**Unit**	**PM**	**SO2**	**NO_x**	**CO**	**VOC**	**Pb**	**Total HAPs**
001	turbine	0.0066[a]	0.06016[a]	0.429[c]	0.117[c]	0.0032[c]	ND	0.00103[a]
002	turbine	0.0066[a]	0.06016[a]	0.201[c]	0.528[c]	0.0516[c]	ND	0.00103[a]
003	turbine	0.0066[a]	0.06016[a]	0.461[c]	0.017[c]	0.0006[c]	ND	0.00103[a]
004	gen-erator	0.01[b]	0.000588[b]	4.08[b]	0.557[b]	0.118 [b]	ND	0.097[b]

ND = No Data

a From U. S. EPA AP-42, chapter 3.1 for stationary gas turbines, published April 2000. Percent Sulfur in pipeline quality natural gas defined as 0.064% by weight (40 CFR 72.2 and gas tariff)

b From U. S. EPA AP-42, chapter 3.2 for gas-fired reciprocating engines, published July 2000.

c From April 2000 performance test. VOC is measured as total non-methane hydrocarbons (THC), reduced by 80% to account for VOC only compounds.

PTE Calculations:

$$PTE = \frac{lb}{MMBtu} \times \frac{MMBtu}{hr} \times \frac{8760hr}{yr} \times \frac{0.0005ton}{lb} = tpy$$

$$PTE = EmissionFactor \times MaxHeatI$$

<u>EU 001: 251.1 MMBTU/hr</u>
NO_x: 0.429 lb/MMBTU * 251.1 MMBTU/hr * 8760 hr/yr * 0.0005 ton/lb = 471.8 tpy

<u>EU 002: 166.4 MMbtu/hr</u>
NO_x: 0.201 lb/MMbtu * 166.4 MMbtu/hr * 8760 hr/yr * 0.0005 ton/lb = 146.5 tpy

<u>EU 003: 184.0 MMbtu/hr</u>
NO_x: 0.461 lb/MMbtu * 184 MMbtu/hr * 8760 hr/yr * 0.0005 ton/lb = 371.5 tpy

2.0 APPLICABLE REGULATIONS AND DETERMINATIONS

(A). New Source Performance Standards (NSPS)

EU 001 and EU 003 have a heat input at peak load equal to or greater than 10.7 gigajoules per hour based on the lower heating value of the fuel fired. Additionally, each unit was constructed and/or and has been modified after October 3, 1977. Based on these conditions both units are subject to Subpart GG.

1. NSPS limits for NO_x

   According to Subpart GG of the NSPS, 40 CFR 60.332(d), Standards of Performance for Stationary Gas Turbines, “stationary gas turbines with a manufacturer’s rated base load at ISO conditions of 30 megawatts or less...shall comply with part 60.332(a)(2)”.

   i. EU 001 Applicability

$$31{,}000HP \times \frac{745.54W}{1hp} \times \frac{1MW}{10^6 W} = 23.11MW$$

ii. EU 003 Applicability

$$23{,}000\text{HP} \times \frac{745.5\text{W}}{1\text{hp}} \times \frac{1\text{MW}}{10^6\text{W}} = 17.15\text{MW}$$

iii. NSPS NO_x emission limit 40 CFR 60.332(a)(2):

$$\text{STD} = 0.0150 \times \frac{14.4}{\text{Y}} + \text{F}$$

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph 40 CFR 60.332(a)(3).

= 0, where fuel bound N < or = 0.015% N in fuel by weight.

iv. Conversion equation for Y:

$$\frac{\text{Btu}}{\text{HP}\cdot\text{hr}} \times \frac{1055\text{J}}{\text{Btu}} \times \frac{\text{KJ}}{1000\text{J}} \times \frac{\text{HP}}{745.7\text{W}} = \frac{\text{KJ}}{\text{W}\cdot\text{hr}}$$

v. NSPS limit for EU 001

Y = 7982.4 Btu/hp-hr, actual heat rate from compiled 1995 stack test data

$$\text{Y} = 7982.4\frac{\text{Btu}}{\text{HP}\cdot\text{hr}} = 11.29\frac{\text{KJ}}{\text{W}\cdot\text{hr}}$$

$$STD = 0.0150 \times \frac{14.4}{11.29} = 0.019132\% \text{ by volume}$$

STD = 191 ppmv @ 15% O2 and on a dry basis

vi. NSPS limit for EU 003

Y = 7777.7 Btu/hp-hr, actual heat rate from compiled 1995 stack test data

$$Y = 7777.7 \frac{Btu}{HP \cdot hr} = 11.00 \frac{KJ}{W \cdot hr}$$

$$STD = 0.0150 \frac{14.4}{11.00} = 0.019636\% \quad \text{by volume}$$

STD = 196 ppmv @ 15% O2 and on a dry basis

2. NSPS limits for SO_2

Per 40 CFR 60.333 (b), "...No owner or operator subject to provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight. ..."

Great Lakes' FERC Gas Tariff, Second Revised Volume No. 1, limits the amount of sulfur that may be present in the natural gas in Great Lakes' pipeline system. The FERC tariff provides that total sulfur within the natural gas cannot exceed 20 grains per hundred cubic feet of gas, or 0.064% by weight.

3. NSPS Subpart GG Custom Fuel Monitoring

40 CFR Part 60, Subpart GG was promulgated September 10, 1979 (44 FR 52798, as amended). As part of the promulgation, certain standards and monitoring requirements were established for SO_2 including daily monitoring of sulfur content in the fuel with an option to develop custom schedules for determination of the values once such a schedule can be substantiated. An Agency memorandum from John B. Rasnic, Chief, Compliance Monitoring Branch to Air Compliance Branch Chiefs and Air Programs Branch Chiefs, dated August 14, 1987, discussed custom fuel monitoring

schedules and provided guidance, among other things, on the approval of custom fuel monitoring schedules. This memorandum recommended that "...any schedules Regional Offices issue for natural gas shall be no less stringent than the following: sulfur monitoring should be bimonthly, followed by quarterly, then semiannual, given at least six months of data demonstrating little variability in sulfur content and compliance with §60.333 at each monitoring frequency...". Although nitrogen monitoring was waived for pipeline quality natural gas, the memorandum does not allow any waiver of sulfur monitoring.

Great Lakes has an EPA-approved custom fuel monitoring plan for monitoring fuel sulfur content for EU 001 and EU 003. The custom fuel monitoring plan is used in place of the monitoring requirements for Standards of Performance for Stationary Gas Turbines. Under the plan, nitrogen monitoring is waived while the facility uses pipeline quality natural gas. The facility has demonstrated past compliance with the plan and is now in the stage of the plan that allows sulfur monitoring on a semi-annual basis at CS #5.

EPA’s approval of the custom fuel monitoring plan is contingent upon several conditions or clarifications which must be satisfied as given below:

i. Only pipeline quality natural gas fed directly from the Great Lakes pipeline system is used by Compressor Stations 1, 3, 4 and 5.

ii. The fuel sulfur content measured at CS #5 is representative of the sulfur content of the fuel used by Stations 1, 3 and 4.

iii. The fuel sulfur content measured at CS #5 is an enforceable measurement applicable to Stations 1, 3 and 4.

iv. The approval to allow monitoring at only CS #5 is not considered a waiver of the NSPS required sulfur monitoring at either Stations 1, 3 or 4. Instead, the sulfur monitoring conducted at CS #5 satisfies the monitoring requirements for Stations 1, 3 and 4.

v. Great Lakes notifies EPA and the Fond Du Lac Band of Lake Superior Chippewa before any new turbine is added along the pipeline.

Note that the above approval does not waive the right of EPA under section 114 of the CAA, 42 U.S.C. Section 7414, or any other authorized regulating entities to require monitoring at other stations (i.e., Stations 1, 3 or 4), as well as CS #5, for compliance determinations. Furthermore, if the sulfur monitoring at CS #5 reveals a sulfur content in excess of that specified in 40 CFR Part 60, Subpart GG, Great Lakes could be required to increase the monitoring frequency in accordance with 40 CFR Part 60, Subpart GG and applicable guidance documents. Such an exceedance may also lead to a future determination requiring monitoring at additional stations and possible enforcement action. Finally, the above approval is based on federal regulations and provides the minimum conditions for compliance. EPA maintains the right to require more stringent requirements than those outlined above.

The “Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes” is an EPA approved alternative method to American Society for Testing and Materials (ASTM) methods for fuel sulfur content monitoring for natural gas-fired turbines subject to NSPS Subpart GG. This method was approved in an EPA Determination Detail, Control Number NS08, dated August 7, 1991, from Mamie Miller, Compliance Monitoring Branch Chief, Stationary Source Compliance Division.

(B). New Source Review (NSR)

1. Applicability

The potential emissions for CO and NO_x at CS #5 are greater than 250 tons per year (tpy). St. Louis County, and all Indian Country within (Fond du Lac Band of Lake Superior Chippewa Indian Reservation), is designated attainment for all criteria pollutants. Therefore, CS #5 is a major source and as such is subject to the PSD provisions [40 CFR 52.21(b)(1)].

CS #5 was built prior to June 1, 1975, the date of applicability for the predecessor NSR program comparable to PSD, Significant Deterioration of Air

Quality, 40 CFR 52.21 (1975). Three modifications to the facility were made after June 1, 1975 (the full replacement of EU 001 in 1989; the installation of EU 003 in 1992; and the replacement of EU 004 in 1993). Consequently, PSD applicability to individual units is based upon installation date and the potential to emit of each unit.

i. EU 002 was installed in 1969, which is prior to the date of applicability for PSD, and has not been modified since installation. EU 002 is therefore not subject to PSD review.

ii. EU 001 was installed in 1989 to replace an aging but similar natural gas-fired turbine that was originally installed in 1971. At the time, CS #5 was an existing major stationary source and the NO_x emissions increase due to this reconstruction exceeded the 40 tons per year threshold for a major modification in 40 CFR 52.21(b)(23). This emissions increase would have therefore been considered a major modification subject to PSD. However the emissions from EU 001 were offset by an equal emissions decrease obtained from the removal of the turbine unit originally installed in 1971, such that the net emissions increase was zero, and therefore less than the significant net emission increase threshold for NO_x (detailed in the supporting documents submitted with the Part 71 permit application). Additionally, the fuel usage and emissions from the new turbine are less than from the old, less efficient turbine. Great Lakes was therefore not required to go through PSD review for NO_x for the installation of EU 001.

iii. The addition of EU 003 in 1992 was a major modification subject to PSD review since the facility was an existing major source, and the new turbine was projected to emit more than 40 tons per year. PSD review was completed for EU 003 under a construction permit application submitted to MPCA in November 1991.

iv. EU 004 was originally installed in 1968. The replacement of EU 004 with a new standby electrical generator in 1993 constituted a major modification to a major source based upon the unrestricted potential of the replacement generator [40 CFR 52.21]. The installation of the replacement generator was not included in the 1991 PSD permit application calculations and analyses that were performed for the installation of EU 003. At the time of installation of EU 004, Great Lakes proposed a federally enforceable limit on the number of hours of operation per year, in order to keep the net emission increase of NO_x below the 40 tons per year significant emission increase threshold, thus the construction of the generator was not required to go through PSD review. According to facility records, actual 1994 operation of the generator was approximately one hour per month.

The natural gas-fired standby electrical generator is a Caterpillar, model SR-4 with a rated heat input of 4.80 MMBtu/hr. The original standby generator, which was a Koehler, model 170R72, had a rated heat input of 2.19 MMBtu/hr. The rated heat input for both generators was calculated using 8,000 Btu/HP-hr as the heat rate factor.

The net emissions increase of criteria and hazardous air pollutants due to this replacement was calculated as follows:

net emissions increase = future potential - past actual

Unrestricted future potential emissions from the new Caterpillar generator were calculated assuming 8760 hours of operation. Past actuals from the original Koehler generator were calculated by multiplying PTE figures by 0.0014 (equivalent to 1 hr/mo). The unrestricted net emission increase of NO_x was greater than the 40 tons per year PSD threshold. Therefore, Great Lakes proposed an enforceable operational limit, whereby, the operation of the proposed standby electrical generator was restricted to no more than 4,500 hours per year. This limitation resulted in a NO_x restricted net emissions increase of 34.5 tons per year, thus eliminating the requirement to perform a PSD review for the installation of the replacement generator.

The unrestricted and restricted net emissions increases of criteria pollutants and HAPs, due to the installation of the replacement generator, are shown in the table below.

EU 004

Pollutant	PM tpy	SO_2 tpy	NO_x tpy	CO tpy	VOC tpy	Pb tpy	Total HAPs tpy
Original Generator Past Actuals	0.000	0.000	0.051	0.007	0.003	0	0.000
Current Generator Unrestricted Future Potentials	0.000	0.000	67.3	8.83	3.78	0	0.144
Current Generator 4,500 hrs/yr with limit	0.000	0.000	34.6	4.54	1.94	0	0.074
Unrestricted Net Emissions Increase	0.000	0.000	67.2	8.82	3.78	0	0.144
Restricted Net Emissions Increase	0.000	0.000	34.5	4.53	1.94	0	0.074

Additionally, the PSD minor source baseline date for St. Louis County was triggered in 1991. Therefore, PSD increment consumption applies to all emission changes since 1991. Operating EU 004 at the 4,500 hour per year limit, future potential emissions from the 1991 trigger date exceed the maximum allowable PSD increment ceiling of 25 $\mu g/m^3$ for CS #5. In 1998, Great Lakes obtained a permit from the MPCA which included a federally enforceable limit on operation of the generator of 3,000 hours per year. This limit effectively; 1) reduced the emissions of the generator below PSD thresholds, and 2) reduced future potential emissions to below the maximum allowable PSD increment for the area. EPA is including this 3,000 hour per year limit for EU 004 in its PSD permit to assure that it remains federally enforceable and that the annual PSD NO_x increment is protected.

2. Best Available Control Technology for EU 003

The BACT analysis is an analysis of the pollution control technology available to any new stationary source that can be used to achieve emissions reductions. It is a “top-down” process in which all available control technologies are ranked from highest to lowest in order of effectively reducing air emissions. In the “top-down” process, the PSD applicant first examines the most stringent, or “top” control alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgement agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not feasible in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. The BACT analysis is done on a case-by-case basis. The EPA provides guidance on conducting BACT analyses in the NSR Workshop Manual (DRAFT, October 1990).

As stated above in section (3.1)(B)(iii), the installation of EU 003 is subject to the PSD regulations and requires that a BACT determination be preformed for NO_x. The BACT analysis, as follows, was submitted to MPCA with the original permit application for the 1992 installation of EU 003. As previously discussed, EPA will evaluate the BACT analysis according to what was accurate within the time-frame of the original permit issuance.

i. Identification of Control Technologies

There are two basic approaches to controlling NO_x emissions from natural gas-fired compressors. One involves engine or turbine modifications and/or changes to operating parameters to inhibit NO_x formation in the combustion process. The other involves after treatment to reduce NO_x concentrations in the exhaust gas.

Technology	**Status**	**NO_x Emission Concentration**	**Type of Control**
Improved Dry controls	Available in 1995	25 ppm	Turbine Modification
Selective Catalytic Reduction (SCR)	Not installed in pipeline applications	32 ppm	After Treatment
Selective Non-Catalytic Reduction (SNCR)	Not installed in pipeline applications	Unknown	After Treatment
Water Injection	Not installed in pipeline applications	42 ppm	Turbine Modification
Existing Dry Controls	In Use	160 ppm	Turbine Modification

ii. Review of Control Technologies

In its 1992 BACT analysis, Great Lakes recommenced Existing Dry Controls for reducing NO_x emissions and eliminated the other technologies for various reasons. Great Lakes held that:

Improved dry combustion technology was common for large turbines but was not available at the time for the turbine size needed at the Great Lakes facility. MPCA therefore concluded that this technology was not technologically feasible in an adequate time-frame for the initial turbine operation.

The major concern with applying Selective Catalytic Reduction (SCR) to the EU 003 was the temperature of the exhaust gases from the combustion turbine. Exhaust temperatures are related to load conditions and ambient temperature conditions. These varying exhaust-gas-temperature conditions reduce SCR control efficiency. In addition, a given catalyst exhibits optimum performance within a narrow temperature range, and wide temperature swings cause thermal stress on the catalyst, reducing performance, and increasing long-term NO_x and ammonia emissions at the facility.

In addition to the variable nature of the exhaust gas temperature, the temperature of the turbine exhaust was too high for the proven base-metal catalysts. In order to use this technology, a heat recovery steam generator (HRSG) or an air-to-air heat exchanger is required to cool the exhaust system. The installation of a HRSG for the purpose of exhaust-gas temperature reduction was incompatible with the planned operation of the unit. The energy, environmental and costs impacts of using a HRSG would also be prohibitive. An air-to-air heat exchanger had never been used in an application of this type, therefore this type of exhaust temperature cooling was considered to be unproven. Additionally, energy costs to drive the fans to operate the air-to-heat exchanger were estimated to be prohibitive.

The exhaust gas of the proposed unit is not hot enough to allow for successful operation of Selective Non-Catalytic Reduction (SNCR) control. There had been no successful demonstrations of this technology for this type of application in 1992. MPCA concluded that SNCR was therefore not technically feasible for this application and excluded from the BACT analysis for this facility.

Injecting water or steam into the primary combustion zone had been shown to reduce NO_x emissions from gas-fired turbines to 42 ppm. Because steam is not produced in sufficient quantities at CS #5, steam injection was not technically feasible for this application. Although water injection was an effective means of suppressing NO_x from gas turbines, this control method had not yet been applied to any operating compressor drive turbines at natural-gas pipeline stations in either new or retrofit installations. Water injection can cause significant damage to the turbines due to impurities in the water. The installation and maintenance of a water treatment system would have added considerably to the capital costs of the project and increased the risk of system downtime. Using water injection had also been shown to have a negative effect on the energy efficiency of turbine units. The economic analysis for implementing water injection determined that the annual cost per ton of NO_x removal using water injection for this unit was cost prohibitive.

Additionally, there were environmental considerations when using water injection for NO_x control. To reduce the NO_x emissions from the facility by approximately 231 tons per year, 22,800 gallons of water would have been needed for each ton of NO_x removed from the atmosphere. The implementation of water injection would have also produce 1.6 million gallons of wastewater. Water injection would have also caused CO emissions to increase.

Based on the technical, economic, and environmental evaluations contained in the BACT analysis, MPCA determined in 1992 that BACT for EU 003 was existing dry controls, with a NO_x emission rate of 160 ppm. This emission rate is 18% below the NSPS of 196 ppm, and is achievable with standard turbine design and operation. Compliance with the more stringent BACT limit can be considered compliance with the NSPS limit.

iii. BACT Limit for EU 003

A time based BACT limit (e.g., lb/hr) is necessary to make sure that a source emitting at its BACT emission concentration limit does not emit more pollutant than assumed in the ambient analysis applicable at the time of MPCA's PSD permit issuance.

The GE LM 1600 turbine performance varies with load. A summary of the performance characteristics as presented in the PSD permit application (National Electric Manufacturing Association (NEMA) rating), is presented below:

Shaft HP.........................15,680 HP
Heat Rate........................7342 Btu/HP-hr
Ambient Temp.....................80°F
NEPA Fuel Consumption Rate..........115,123 ft^3/hr
NO_x Emission Rate.................159.3 ppm
NO_x Emissions at NEPA Fuel Burn...71.5 lb/hr

% O2, by volume, wet............ .14.52

Conversion of ppm to lb/MMBtu:

$$ER = C \times MW \times 2.59E\text{-}09 \times Fd \times \frac{20.9}{(20.9 - O_2)}$$

ER = Pollutant Emission Rate (lb/MMBtu)
C = Pollutant concentration @ 15% O_2 and on a dry basis
MW = Molecular weight of NO_x (46)
2.59E-09 = Conversion Factor at 60°F
Fd = EPA fuel factor (8710 dscf/MMBtu)
$\%O_2$ = Exhaust Gas Oxygen Content (% volume, dry)

$$ER = 160 \times 46 \times 2.59E - 09 \times 8710 \times \frac{20.9}{(20.9 - 15)}$$

$$ER = 0.5882 \frac{lb}{MMBtu}$$

Calculation of BACT limit:

Heat Content for natural gas = 1000 Btu/scf

$$\frac{0.5882\ lb}{MMBtu} \times \frac{115{,}123\ scf}{hr} \times \frac{1000\ Btu}{scf} \times \frac{MMBtu}{10^6\ Btu} = 68 \frac{lb\ NO_x}{hr}$$

$$68 \frac{lb\ NO_x}{hr} = 298 \frac{tons\ NO_x}{yr}$$

iv. Total NO_x emissions from EU 003 shall not exceed 68 lb/hr.

The Permittee shall monitor, in accordance with an EPA approved plan, the pounds per hour, as well as parts per million by volume, of NO_x emitted from EU 003. A monitoring plan shall be submitted for approval by EPA within 90 days from the effective date of this permit. The monitoring plan shall include monitoring equipment siting, operating, and maintenance plan and procedures. If EPA identifies any problems with the monitoring plan the Permittee shall revise the plan to address the problems to EPA's satisfaction within an additional 90 days. Upon approval by EPA, the Permittee will immediately begin to comply with the monitoring plan.

3. Air Quality Analysis

The PSD review requires an applicant to conduct an air quality analysis of the ambient air impacts associated with the construction and operation of the proposed new source. The main purpose of an air quality analysis is to demonstrate that new emissions emitted from the proposed major stationary source, in conjunction with other applicable emissions from existing sources in the area, will not cause or contribute to a violation of any applicable National Ambient Air Quality Standards (NAAQS) or PSD increment. An air quality analysis is also required for any pollutant increases from a proposed new or modified source planning to construct within 100 kilometers of a Class I area and which has an ambient impact on such an area equal to or greater than 1 micrograms per cubic meter ($\mu g/m^3$), based on a 24-hour average.

A PSD permit was required for the installation of EU 003, therefore, Great Lakes completed modeling of NO_x emissions from CS #5. As part of the 1992 NSR application to MPCA, an analysis of ambient air impacts, increment (dispersion modeling) and visibility was completed. An air-quality analysis was performed for the CS #5 as it existed and also with the addition of EU 003. The dispersion modeling analyzed impacts of NO_x and CO from the facility. Two dispersion models were used.

For NO_x, the preferred Industrial Source Complex - Long Term (ISCLT) Version 90008 model was used. For CO, the EPA SCREEN model was used. The model results showed no significant impact beyond a 1/4 mile radius from the source. Predicted impacts from the proposed addition were well below the *de minimis* levels for NO_x and CO. Based on these modeling results MPCA determined CS #5 to be in compliance with all requirements under the Act and PSD and approved the installation of EU 003 (Amendment No. 1 to Permit No. 365B-89-OT-1 issued July 9, 1992).

In January 1998, the Braun Intertec Corporation performed a dispersion modeling analysis of the estimated ambient air concentration of NO_x for CS #5. The purpose for performing this modeling was to demonstrate that the facility parameters, as identified in the 1995 Title V Permit application to MPCA, complied with the NAAQS for NO_x. Potential emissions input to the model are as follows:

EU 001 = 216.5 lb/hr = 948.0 tpy
EU 002 = 44.2l lb/hr = 193.7 tpy
EU 003 = 122.2 lb/hr[3] = 535.1 tpy

The current version of the EPA approved dispersion model “Industrial Source Complex Short Term 3" (ISCST3) was used. The highest fence-line NO_x concentration modeled for the facility was 77.4 µg/m^3. After adjustments, the modeling shows that the annual NO_x concentration impacts (74.1 µg/m^3) comply with the NAAQS for NO_x (100 µg/m^3).

The PSD minor source baseline date for St. Louis County was triggered in 1991. Therefore, PSD increment consumption applies to all emission changes since 1991. In April 1998, Great Lakes performed dispersion modeling to verify acceptable levels of NO_x increment consumption since the triggering of the minor source baseline date. The increment consumption evaluation consisted of estimating the annual NO_x impact prior to the minor source NO_x baseline date, and then comparing that value to the current annual NO_x impact at each compressor station. The resulting difference between current and past impact levels was then compared to the PSD NO_x allowable increment standard of 25 µg/m^3. It was shown that future potential emissions from the 1991 trigger date for EU 004 exceeded the maximum allowable PSD increment ceiling of 25 µg/m^3. However, the

[3] 122 lbs/hr is significantly higher and thus more conservative than the 68 lb/hr that EPA is proposing.

increment evaluation also demonstrated that operation of the electrical generator at less that 3,000 hours per year will prevent this exceedance of the allowable increment.

Dispersion modeling methodology used for the increment consumption evaluations conformed to all federal and state guidance. Specific increment consumption concentration values at individual receptors were obtained by modeling future potential and estimated past actual (Emission Inventory data) emission rate values. The emission rates for NO_x as input into this model are:

EU 001 = 216.5 lb/hr = 948.0 tpy
EU 002 = 44.2l lb/hr = 193.7 tpy
EU 003 = 122.2 lb/hr[4] = 535.1 tpy
EU 004 = 5.27 lb/hr[5] = 23.1 tpy

Modeling reflects future potential emissions for EU 004 at 3000 hours per year. The final increment modeling shows a maximum annual incremental NO_x concentration of 22.7 $\mu g/m^3$. This meets the NO_x increment ceiling of 25 $\mu g/m^3$.

The NO_x incremental modeling completed in 1998 is compatible with the current US EPA modeling guidance. The key modeling elements were:

- Industrial Source Complex Short Term model (ISCT3, version 97363);
- Building Profile Input Program (version 95086) pre-processor for ISCST3;
- Flat terrain at 154 receptors; and
- 1987-1991 Fargo, ND, and ST. Cloud, MN, meteorological data.

4. Additional Impact Analysis

For the additional impact analysis, the applicant must examine growth in the area due to the project, analyze the impacts of emissions from the project on the

[4] 122 lbs/hr is significantly higher and thus more conservative than the 68 lb/hr that EPA is proposing.

[5] 15.4 lbs/hr adjusted for 3000 hr limit, averaged to lb/hr on an annual basis.

ambient air quality and the soils and vegetation in the area, and analyze any visibility impairment due to the project. The additional impact analysis showed no significant impacts on visibility, soils and vegetation in the surrounding area.

5. Class I Area Impact Analysis

For sources that have the potential to impact PSD Class I areas, additional analyses need to be conducted to demonstrate compliance with PSD Class I area increments, as well as any impacts on Air Quality Related Values associated with the PSD Class I area such as, visibility, water quality, flora and fauna.

There are no Class I areas within 100 kilometers of CS #5, therefore, no Class I Area Impact analysis is necessary.

3.0 Emission Limits Summary

Emission Unit	Limit	Applicable Reg.
EU 001	NO_x < or = to 191ppm @ 15% O_2 and on a dry basis	NSPS - 40 CFR Part 60, Subpart GG
EU 003	NO_x < or = to 160ppm @ 15% O_2 and on a dry basis	PSD BACT limit 40 CFR Section 52.21
EU 003	NO_x < or = to 68 lb/hr @ 15% O_2 and on a dry basis	PSD BACT limit 40 CFR Section 52.21
EU 001 EU 003	Fuel Sulfur Content <or = 0.8% by weight	NSPS - 40 CFR Part 60, Subpart GG
EU 001 EU 003	EU's can burn only natural gas drawn directly from the pipeline.	NSPS - 40 CFR Part 60, Subpart GG, Custom Monitoring Plan

EU 004	Operating hours limit of < or = to 3,000 hours per year using a 12 month rolling sum.	NSR - 40 CFR 52.21

4.0 Compliance Summary

Requirement	Associated Monitoring, Recordkeeping and Reporting
Fuel Sulfur Content < or = to 0.8% by weight	Analysis for sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels. The reference methods are: ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82. [40 CFR 60.335(b)(2)] The "Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes" is an EPA approved alternative method to ASTM methods for fuel sulfur content monitoring for natural gas-fired turbines subject to NSPS Subpart GG. Sample analysis shall be conducted twice per annum, during the first and third quarters of each calender year. Records of sample analysis and fuel supply pertinent to the custom schedule shall be retained for a period of five years.
EU's can burn only natural gas drawn directly from the pipeline.	Normal operation of the pipeline does not allow natural gas to enter the pipeline between Compressor Station Nos. 3, 4, and 5.
EU 001 NO_x < or = to 191 ppm @ 15% O_2 on dry basis	Performance tests shall be completed within 12 months from the effective date of the permit and every five years following. [40 CFR 60, App A]

EU 003 NO_x < or = to 160 ppm @ 15% O_2 on dry basis	Performance tests shall completed within 12 months from the effective date of the permit and every five years following. [40 CFR 60, App A]
EU 003 NO_x < or = to 68 pounds per hour and NO_x < or = to 160 ppm @ 15% O_2 on dry basis	The Permittee shall monitor, in accordance with an EPA approved plan, the pounds per hour, as well as parts per million by volume, of NO_x emitted from EU 003. A monitoring plan shall be submitted for approval by EPA within 90 days from the effective date of this permit. The monitoring plan shall include monitoring equipment siting, operating, and maintenance plan and procedures. If EPA identifies any problems with the monitoring plan the Permittee shall revise the plan to address the problems to EPA's satisfaction within an additional 90 days. Upon approval by EPA, the Permittee will immediately begin to comply with the monitoring plan.
EU 004 Operating hours limit of < or = to 3,000 hours per year using a 12 month rolling sum.	Total operating hours of EU 004 shall not exceed 3,000 hours per 12-consecutive month period, with compliance determined at the end of each month (12-month rolling sum).